Indiana Office of Utility Consumer Counselor
Comments Regarding the IURC
Advanced Notice of Proposed Rulemaking on Distributed Resources
March 1, 2002

Responses to the IURC list of questions 'a' through 's':

a. Please provide a definition of distributed generation, including engineering characteristics and unit size. Should the definition differ depending on the customer class?

"Distributed generation" is generation that is not located at a central generation station. Just how decentralized it needs to be in order to qualify for special treatment under a distributed generation tariff is a matter for discussion. The OUCC believes that the Commission should make a distinction between two different kinds of distributed generation in its rulemaking—a distinction that follows from what seem to be two different common views of what the term "distributed generation" means. The first category can be defined as:

1) Generation that is very small scale (i.e. less than 10 or 20 or 100 kW capacity[1]) and environmentally friendly (either using no fossil fuels (photovoltaic, wind, etc.) or using fossil fuels very efficiently on a very small scale (e.g. fuel cells). We will refer to this as a "Type 1" generator.

This contrasts with a second category of distributed generation pertaining to system reliability and peak demand cost reduction (for industrial customers):

2) Generation that is larger scale (for example, up to 15 MW as defined in Wisconsin statute[2]) and is "economic" in the sense that these facilities reduce the cost of maintaining system reliability or reduce the overall electricity bill for an industrial customer (through reducing peak demand charges). Typical technologies for this application include diesel engines and microturbines. We will refer to this as a "Type 2" generator.

While all customers are interested in reducing their cost of electric service and maintaining reliability, these goals form the main focus for Type 2 DG, while environmental benefits and very small scale advanced technology are the focus of Type 1 installations.

The OUCC believes these two types of distributed generation should be treated differently in an IURC rulemaking. While we would all like to see photovoltaics, wind power and combined heat/power residential fuel cell installations develop and succeed,

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[1] See attached DOE summary of state net metering programs. Most states' limits on the size of DG to qualify for their net metering programs fall below 100 kW.
[2] Wisconsin statute 196.496; can be accessed at www.legis.state.wi.us/rsb/stats.html

the reality is that at this time not all can afford to install these kinds of units. Thus, even without a limit to the total amount of kW installed and size per installation (as is implemented by law in most states to qualify for net metering—see attachment), it is unlikely that these types of installations will have a material effect on utility revenues/costs for a number of years. Also, because of that small overall quantity of installations, any reasonably small degree of subsidies (due to, for example, ignoring "stranded distribution assets") afforded to these units in the design of their tariffs should be negligible. Furthermore, in exchange for a small subsidy, it seems reasonable for the Commission to consider the benefits to the state arising from the implementation and development of such environmentally friendly electricity supply alternatives.

In contrast, the relatively large installation size and near-term economic attractiveness of distributed generation units under the second definition above leaves the potential for significant rate impacts to customers. In addition, these more practically-motivated installations are less likely to have offsetting environmental benefits for the state. For these reasons, it is important that the Commission ensure that the economic incentives for building these units do not result in subsidies leading to economic inefficiency and undue rate increases for customers.

The OUCC will orient its answers to the remaining questions asked by the Commission within this framework of a "dual" approach to defining distributed generation.

b. Assuming net metering as the first step in a DG rulemaking, what are the benefits for customers with net metering and what are the possible negative effects?

Net metering, which is essentially "running the meter backwards" for flows into the electric grid, is the simplest approach to providing for distributed generation. It requires no special calculations of rates or special meters[3]. Consequently, the cost of administration is low, and so this approach is well-suited to the kind of low-volume participation expected under the Type 1 category of distributed generation.

The disadvantage of a net metering approach is that it does not provide compensation that is directly related to the marginal value of the electricity being sold back to the utility. It includes a transmission and distribution component that is not related to the value of the electricity sold back. In addition, the DG's tariffed electric rate reflects the average cost[4] of providing electricity, not its marginal cost (which might be higher or lower, or higher on one day and lower on another). This could either lead to a subsidy to the generator (if marginal cost is less than average cost) or encourage an inefficiently small amount of such generation (if the utility's marginal cost is greater than its average cost).

Since a utility's marginal cost of providing electricity is only coincidentally equal to its average cost, the use of net metering will only coincidentally lead to an economically efficient result. Again, for small amounts of Type 1 generation, the problem is not big

[3] There might be a meter change necessary in some instances, but does not require the kind of sophisticated meter that might be needed with more complex forms of electricity buy-back.
[4] Ignoring for the moment Indiana's "fair value" approach to ratemaking.

enough to worry about. However, for Type 2 generation, where the potential consequence for electric rates is large, net metering should not be used. Rather, prices for buy-back should be set at an economically efficient level independent of the DG's tariffed electric rate.

c. What kind of tariff structure can be used to deal with different amounts and sizes of DG and still make net metering practical?

As alluded to above, a "net metering" tariff structure seems appropriate for the small amounts of generation envisioned in the OUCC's "Type 1" distributed generation defined above. This is the same general approach to compensation as if the customer were to install a more efficient heat pump or energy efficient lighting—"payment" is the reduction to the DG's electric bill at the tariffed rate. This leaves open the question of what happens if the generator puts more electricity onto the grid during the month than he/she uses. This, on the DOE attachment to these comments, is called "Net Excess Generation" ("NEG").

Different states treat compensation for NEG in different ways. Some states grant those overages to the utility. Some provide for compensation at the utility's avoided cost. Others credit the overage to the next-month's bill. This final approach seems the best for Type 1 distributed generation, since it is the simplest (as discussed earlier)[5]. Because of the potential for this approach to overstate the value of that electricity to the utility, it seems reasonable to limit the total amount of such DG that may participate on a utility's system (see attachment for approaches of different states in setting limitations: e.g. 0.2% of annual peak demand in Georgia and 105 MW in Iowa). To the extent that a utility sees a decrease in revenue from the DG program, it will be likewise limited. If the utility believes such losses to be significant, it is free to come to the Commission to have its rates reviewed. If/when small scale DG becomes more economically viable, the Commission will need to reopen consideration of compensation for this category.

For Type 2 distributed generation (defined in 'a' above) the OUCC believes that a reasonable approach would be to require two meters at the facility—one to measure output from the generator and one to measure flows from and onto the utility system.[6] Using the output of these meters, the DG's load can be determined and charged at its normal tariffed rate. Separately and additionally (though in the same tariff), the electricity generated (not the net amount of electricity put onto the grid) would be compensated at the utility's avoided cost of obtaining generation[7]. While this approach is different than might have been envisioned, the OUCC hopes that the Commission will consider it as potentially the most straightforward manner of accounting for the costs and

[5] While giving the overage to the utility would also be quite simple, it seems reasonable to grant this small incentive to those investing in the small, environmentally friendly kinds of "Type 1" facilities.

[6] Note that both PSI Energy and IPL reserve the right to put such meters on the output of generation equipment in their photovoltaic net metering tariffs. The PSI Energy net metering rider can be accessed at: www.cinergycge.com/PSIElecTariff/pdf/rider57.pdf

[7] That avoided cost value should include consideration of the characteristics of the power provided to the utility (e.g. the liklihood of it being available when needed by the utility).

benefits of these generators and leading to clearly appropriate incentives for their construction.

A good start on defining an appropriate level of compensation for electricity generated by a Type 2 DG can be found in the Commission's detailed rule pertaining to setting buy-back rates for cogeneration and alternate production facilities (170 IAC 4-4.1). This rule should be reviewed in detail to ensure that it is appropriate for this purpose, but it appears to address the same kinds of issues that would be appropriate regarding DG. The level of compensation calculated in that rule could be supplemented by foregone distribution facility investments to the extent that they are clearly foregone as a result of the DG investment.

d. How should a utility determine the fixed amount of cost per customer with net metering, for both a net buyer and/or net seller?

For Type 1 generators, it seems reasonable that the normal customer charge should be paid by the customer each month as a contribution to fixed costs. Beyond this, calculation of fixed costs would not be needed under the OUCC proposal.

For Type 2 generators calculation of fixed costs is also not needed under the OUCC proposal. Since the generator will be paying its normal tariffed rate for electricity consumed in the facility (and separately receiving compensation for the electricity generated), fixed costs are fully paid.

e. How do tariffs need to be designed to adequately reflect the efficient recovery of the fixed and variable costs for service to customers that operate DG equipment using a net meter?

As discussed above, for smaller Type 1 customers it seems reasonable to overlook these fine details in the Commission's rulemaking at this time. For Type 2 customers the OUCC proposal for calculating electricity consumed separate from electricity generated (not net electricity put onto the grid) eliminates the need to make this distinction in the rule or to calculate "stranded costs".

f. How can stranded costs be identified and measured?

See answer to 'e.'

g. What, if any, are the benefits and revenues that should be considered as offsets to stranded costs?

See answer to 'e.'

h. What rate design alternatives would reduce the potential for any stranded costs?

See answer to 'e.'

i. Should standby rates for backup power be used, and if so under what criteria?

If a Type 2 generator taking power under this tariff is treated as proposed here (pays full tariff for power used and receives full compensation for power generated), then no standby rates are needed—standby compensation is embedded into the valuation of those two quantities. For reasons discussed in section 'a,' the OUCC is not proposing that standby rates be charged to Type 1 generators.

j. What different kinds of standby services do customers with DG require and can the utility reasonably supply?

Under the approach proposed by the OUCC, the retail tariff for Type 2 generators would view the distributed generator as essentially two entities: a consumer of power and a generator of power, just as any wholesale generator on the system (with the difference that the sale is part of a retail tariff). As with any generator in the utility's control area, contingencies must be considered for the service of load should one of the interconnected generators go off-line. The DG becomes just one more of these generating units for which the utility must plan in operating its system reliably. In this approach, the concept of "standby service" is not necessary.

k. In order to determine the necessity and proper design of standby rates we need further information on distribution system design, operations, and cost structure. Please provide any information that might help to develop efficient standby rates.

These considerations would be incorporated into the calculation of the price paid for the DG's generation. See also the answer to question 'j.'

l. Are there areas in Indiana with distribution constraints?

Presently, the OUCC is not aware of areas with distribution constraints. One application of distributed generation that may be especially useful is for voltage support in rural areas.

m. Should utilities be required to file a location-specific set of T&D costs?

This may be a burdensome requirement with little expectation of payoff given the current state of Indiana's distribution and transmission system and may also would lead to very complex tariff structures. This might be useful in the future if a utility can clearly identify a bottleneck area where distribution expansion is not feasible or is prohibitively expensive.

n. What constitutes an economically efficient buy-back rate?

See the answer to 'c' above, referencing 170 IAC 4-4.1.

o. What information should be included in a utility standard application form for distributed generation?

A detailed discussion of data requirements is provided in a January 2000 report to the National Association of Regulatory Utility Commissioners "Review of Utility Interconnection, Tariff and Contract Provisions for Distributed Generation," prepared by R.W. Beck and Distributed Utilities Associates. That report presents information on a range of other technical issues related to distributed generation and provides guidance as to what should be addressed in a DG application. Due to the electronic filing of these comments and the length of that document, we will not attach it to this document. It can be downloaded from www.distributed-generation.com/library.htm.

p. What costs are incurred by a utility to review a DG project?

The OUCC believes that it is best for utilities to first answer this question and hopes that the Commission will provide the opportunity to comment on those responses at an appropriate time.

q. Do these costs vary for different DG project proposals?

See answer to question 'p.'

r. How long should it take a utility to evaluate a proje ct?

See answer to question 'p.'

s. What are the criteria a utility should use to evaluate a DG project?

The utility should evaluate the project for safety and to ensure that it will not degrade service of other users on the distribution system. See for example rules created by the Wisconsin PSC (PSC 113.0207)[8]. The utility should not, and should not need to (using the OUCC proposal here), evaluate the economics of a DG project.

[8] Can be accessed at: www.legis.state.wi.us/rsb/code/index.html

Attachment A – DOE Summary of State Net Metering Programs

Last updated on 1/9/02 per downloaded DOE file

Can be Accessed at: www.eren.doe.gov/greenpower/netmetering/nmtable.shtml

State	Allowable Technology and Size	Allowable Customer	Statewide Limit	Treatment of Net Excess Generation (NEG)	Authority	Enacted	Scope of Program	Citation/Reference
Arizona	Renewables and cogeneration ≤100 kW	All customer classes	None	NEG purchased at avoided cost	Arizona Corporation Commission	1981	All IOUs and RECs	PUC Order Decision 52345, Docket 81-045
Arkansas	Renewables, fuel cells and microturbines ≤25 kW residential ≤100 kW commercial	All customer classes	None	TBD by Public Service Commission	Legislature	2001	All utilities	HB 2325, effective Oct. 2001
California	Solar and wind ≤1000 kW	All customer classes	None	Annual NEG granted to utilities	Legislature	2001/ 1995	All utilities	Public Utilities Codes Sec. 2827 (amended 04/01; effective 9/98)
Colorado	Wind and PV 3 kW, 10 kW	Varies	NA	Varies	Utility tariffs	1997	Four Colorado utilities	PSCO Advice Letter 1265; PUC Decision C96-901 [1]
Connecticut	Renewables and fuel cells ≤100 kW	Residential	None	Not specified	Legislature	1990, updated 1998	All IOUs, No REC in state.	CGS 16-243H; Public Act 98-28
Delaware	Renewables ≤25 kW	All customer classes	None	Not specified	Legislature	1999	All utilities	Senate Amendment No. 1 to HB 10
Georgia	Solar, wind, fuel cells ≤10 kW residential ≤100 kW commercial	Residential and commercial	0.2% of annual peak demand	Monthly NEG or total generation purchased at avoided cost or higher rate if green priced	Legislature	2001	All utilities	SB93
Hawaii	Solar, wind, biomass, hydro ≤10 kW	Residential and small commercial	0.5% of annual peak demand	Monthly NEG granted to utilities	Legislature	2001	All utilities	HB 173
Idaho	All technologies ≤100 kW	Residential and small commercial (Idaho Power only)	None	Monthly NEG purchased at avoided cost	Public Utility Commission	1980	IOUs only, RECs are not rate-regulated	Idaho PUC Order #16025 and #26750 (1997) Tariff sheets 86-1 thru 86-7
Illinois	Solar and wind ≤40 kW	All customer classes; ComEd only	0.1% of annual peak demand	NEG purchased at avoided cost monthly plus annual payment to bring payment to retail rate	ComEd tariff	2000	Commonwealth Edison	Special billing experiment [1]
Indiana	Renewables and cogeneration ≤1,000 kWh/month	All customer classes	None	Monthly NEG granted to utilities	Public Utility Commission	1985	IOUs only, RECs are not rate-regulated	Indiana Administrative Code 4-4.1-7
Iowa	Renewables and cogeneration (No limit per system)	All customer classes	105 MW	Monthly NEG purchased at avoided cost	Iowa Utility Board	1993	IOUs only, RECs are not rate-regulated[2]	Iowa Administrative Code [199] Chapter 15.11(5)
Maine	Renewables and fuel cells ≤100 kW	All customer classes	None	Annual NEG granted to utilities	Public Utility Commission	1998	All utilities	Order # 98-621 RC of ME Chapter 36
Maryland	Solar only ≤80 kW	Residential and schools only	0.2% of 1998 peak	Monthly NEG granted to utilities	Legislature	1997	All utilities	Article 78, Section 54M
Massachusetts	Qualifying facilities	All customer	None	Monthly NEG purchased	Legislature	1997	All utilities	Mass. Gen. L. ch. 164,

	≤60 kW	classes		at avoided cost				§1G(g); Dept. of Tel. and Energy 97-111
Minnesota	Qualifying facilities ≤40 kW	All customer classes	None	NEG purchased at utility average retail energy rate	Legislature	1983	All utilities	Minn. Stat. §216B.164
Montana	Solar, wind and hydro ≤50 kW	All customer classes	None	Annual NEG granted to utilities at the end of each calendar year.	Legislature	1999	IOUs only	SB 409
Nevada	Solar and Wind ≤10 kW	All customer classes	First 100 customers for each utility	Monthly or annual NEG granted to utilities	Legislature	1997	All utilities	Nevada Revised Statute Ch. 704
New Hampshire	Solar, wind and hydro ≤25 kW	All customers classes	0.05% of utility's annual peak	NEG credited to next month	Legislature	1998	All utilities	RSA 362-A:2 (HB 485)
New Jersey	PV and wind ≤100 kW	Residential and small commercial	0.1% of peak or $2M annual financial impact	Annualized NEG purchased at avoided cost	Legislature	1999	All utilities	AB 16. Electric Discount and Energy Competition Act
New Mexico	Renewables and cogeneration	All customer classes	None	NEG credited to next month, or monthly NEG purchased at avoided cost (utility choice)	Public Utility Commission	1999	All utilities	NMPUC Rule 571,
New York	Solar only ≤10 kW	Residential only	0.1% 1996 peak demand	Annualized NEG purchased at avoided cost	Legislature	1997	All utilities	Laws of New York, 1997, Chapter 399
North Dakota	Renewables and cogeneration ≤100 kW	All customer classes	None	Monthly NEG purchased at avoided cost	Public Utility Commission	1991	IOUs only, RECs are not rate-regulated	North Dakota Admin. Code §69-09-07-09
Ohio	Renewables, microturbines, and fuel cells (no limit per system)	All customer classes	1.0% of aggregate customer demand	NEG credited to next month	Legislature	1999	All utilities	S.B. 3 (effective 01/01/01)
Oklahoma	Renewables and cogeneration ≤100 kW and ≤25,000 kWh/year	All customer classes	None	Monthly NEG granted to utility	Oklahoma Corporation Commission	1988	All utilities	OCC Order 326195
Oregon	Solar, wind, fuel cell and hydro ≤25 kW	All customer classes	0.5% of peak demand	Annual NEG granted to low-income programs, credited to customer, or other use determined by Commission	Legislature	1999	All utilities	H.B. 3219 (effective 9/1/99)
Pennsylvania	Renewables and fuel cells ≤10 kW	Residential	None	Monthly NEG granted to utility	Legislature	1998	All utilities	52 PA Code 57.34
Rhode Island	Renewables and fuel cells ≤25 kW	All customer classes	1 MW for Narragansett Electric Company	Annual NEG granted to utilities	Public Utility Commission	1998	Narragansett Electric Company	PUC Order Docket No. 2710

Texas	Renewables only ≤50 kW	All customer classes	None	Monthly NEG purchased at avoided cost	Public Utility Commission	1986	All IOUs and RECs	PUC of Texas, Substantive Rules, §23.66(f)(4)
Vermont	PV, wind, fuel cells ≤15 kW Farm biogas ≤125 kW	Residential, commercial and agricultural	1% of 1996 peak	Annual NEG granted to utilities	Legislature	1998	All utilities	Sec. 2. 30 V.S.A. §219a
Virginia	Solar, wind and hydro Residential ≤10 kW Non-residential ≤25 kW	All customer classes	0.1% of peak of previous year	Annual NEG granted to utilities (power purchase agreement is allowed)	Legislature	1999	All utilities	Virginia Assembly S1269 Approved by both Assembly and Senate 3/15/99
Washington	Solar, wind, fuel cells and hydro ≤25 kW	All customer classes	0.1% of 1996 peak demand	Annual NEG granted to utility	Legislature	1998	All utilities	Title 80 RCW House Bill B2773
Wisconsin	All technologies ≤20 kW	All retail customers	None	Monthly NEG purchased at retail rate for renewables, avoided cost for non-renewables	Public Service Commission	1993	IOUs only, RECs are not rate-regulated	PSCW Order 6690-UR-107
Wyoming	Solar, wind and hydro ≤ 25 kW	All customer classes	None	Annual NEG purchased at avoided cost	Legislature	2001	All IOUs and RECs	HB 195, Feb. 2001

Notes:

IOU — Investor-owned utility
GandT — Generation and transmission cooperatives
REC — Rural electric cooperative

[1] For information, see the Database of Statet Incentive for Renewable Energy (http://www.dcs.ncsu.edu/solar/dsire/dsire.cfm).
[2] Except for the Linn County Electric Cooperative, which is rate-regulated by Iowa PUC.

The original format for this table is taken from: Thomas J. Starrs (September 1996). *Net Metering: New Opportunities for Home Power.* Renewable Energy Policy Project, Issue Brief, No. 2. College Park, MD: University of Maryland